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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

In the Matter of the Application of	)	
PacifiCorp dba Rocky Mountain	)	**CASE NO. PAC-E-10-09**
Power for Approval of Amendments to	)	
Revised Protocol Allocation	)	**Direct Testimony of Andrea L. Kelly**
Methodology	)	

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-10-09

September 2010

Q. Please state your name, business address and present position with PacifiCorp (the Company).

A. My name is Andrea L. Kelly, and my business address is 825 NE Multnomah Street, Suite 2000, Portland, OR 97232. I am currently employed as a Vice President in Regulation.

Qualifications

Q. Please summarize your education and business experience.

A. I hold a Bachelor's degree in Economics from the University of Vermont and an MBA in Environmental and Natural Resource Management from the University of Washington. After graduate school, I joined the Staff of the Washington Utilities and Transportation Commission. In 1995, I became employed by PacifiCorp as a Senior Pricing Analyst in the Regulation Department and advanced through positions of increasing responsibility. From 1999 through 2005, I led major strategic projects at PacifiCorp including the Multi-State Process (MSP) and the regulatory approvals for the MidAmerican-PacifiCorp transaction. In March 2006, I was appointed as a Vice President in Regulation.

Q. Have you appeared as a witness in previous regulatory proceedings?

A. Yes, I have appeared as a witness on behalf of PacifiCorp in the states of California, Idaho, Oregon, Utah, Washington, and Wyoming.

Purpose and Overview of Testimony

Q. What is the purpose of your testimony?

A. My direct testimony describes the process and approaches leading up to this filing of the proposed 2010 Protocol allocation methodology. Specifically, my direct testimony provides:

- a brief history of the MSP leading up to the adoption of the Revised Protocol;
- a brief history of the work of the Standing Committee workgroup since November 2008 that has culminated in this filing proposing limited amendments to the Revised Protocol;
- an overview of the proposed amendments to the Revised Protocol and the concerns that the amendments are designed to address;
- a discussion of the Company's view of the commission proceedings necessary to process this application; and
- a discussion of the Company's view of processes necessary to ensure successful implementation of the 2010 Protocol through calendar year 2016 and beyond.

I also introduce the other two Company witnesses in this proceeding.

Q. Are you also sponsoring an exhibit to your testimony?

A. Yes. Exhibit No. 1 presents the 2010 Protocol with all of its Appendices. Although I sponsor Appendix A, Company witness Mr. Steven R. McDougal sponsors the remaining Appendices.

Brief History of the Revised Protocol

Q. Please provide a brief history of the events that gave rise to the Revised Protocol.

A. In December 2000, the Company proposed to reorganize itself into six state distribution companies, a generation company and a service company. This Structural Realignment Proposal (SRP) filing was in response to a number of external developments, including: (1) the lack of agreement among regulatory jurisdictions regarding the Company's inter-jurisdictional cost allocation process; (2) direct access initiatives in Oregon and elsewhere; (3) the need to provide independent control of transmission assets consistent with Federal Energy Regulatory Commission (FERC) expectations; (4) fundamental changes that occurred in wholesale power markets; and (5) increasingly divergent policy goals of various state commissions.

Q. What was the outcome of the SRP filings?

A. The SRP filings proved to be controversial - in large measure because of a concern that the proposed restructuring would result in a transfer of jurisdiction from state commissions to the FERC and the Securities and Exchange Commission. Ultimately, a number of parties and some state commissioners encouraged the Company to seek other means of resolving the Company's concerns that did not require a legal restructuring of the Company. The Company was strongly encouraged to initiate an informal process aimed at achieving consensus among interested parties regarding a number of important issues facing the Company. To that end, in March 2002, the Company made an additional set of state filings asking the state commissions to initiate investigations and endorse a collaborative process to address inter-jurisdictional issues facing PacifiCorp. These filings were broadly supported by the state commissions and gave rise to what became known as the MSP. Pending the MSP, the Company agreed to put the SRP filings on hold.

Q. **What occurred in the MSP?**

A. An initial organizing meeting was held in April 2002 in Boise, Idaho. At that first meeting, a schedule of future meetings and objectives for the process were established. A number of additional MSP meetings were held through July 2003, after which the Company made an additional filing with the states seeking ratification of a proposed solution, the Protocol. Additional discussions related to the Protocol continued through September 2004, which resulted in the Company supplementing its filings with the Revised Protocol. Through commission proceedings, the four state commissions of Utah, Oregon, Wyoming and Idaho issued orders adopting the Revised Protocol in late 2004 and early 2005. Utah's and Idaho's adoption of the Revised Protocol was accompanied by rate mitigation mechanisms tied to the difference between the revenue requirement calculated under the Revised Protocol allocation methodology and the revenue requirement calculated under the Rolled-In allocation methodology.

Q. **Who participated in the MSP collaborative meetings?**

A. All of the major meetings were attended in person by in excess of 50 individuals representing some 18 entities from the states of Utah, Oregon, Wyoming, Washington and Idaho. These included representatives of state commission policy staffs, advocacy staffs, industrial customers and consumer groups. A number of other people participated by telephone.

Q. **How would you characterize the overall objectives of the Revised Protocol?**

A. The objectives of the Revised Protocol include:

- allocating PacifiCorp's costs among its jurisdictional states in an equitable manner;
- ensuring PacifiCorp plans and operates its generation and transmission system on a six-state integrated basis in a manner that achieves a least cost-least risk resource portfolio for its customers;
- allowing each state to independently establish its ratemaking policies. Each state is encouraged to consider the impact its decisions have on other states served by PacifiCorp; and
- providing PacifiCorp a reasonable opportunity to recover 100 percent of its prudently incurred costs.

Q. **Does the Revised Protocol contain provisions for continued dialogue among the states?**

A. Yes. Section XIII.B of the Revised Protocol established the Standing Committee. While not abridging the integrity of commission decision-making processes within each respective state, the Standing Committee:

- monitors and discusses inter-jurisdictional allocation issues facing PacifiCorp and its customers;
- helps to organize and direct work group analysis of inter-jurisdictional allocation issues;
- ensures work group analysis is supported by sound technical analysis;
- shares views on possible amendments to the Revised Protocol, as they may arise;
- seeks consensual resolution of issues arising under the Revised Protocol;

- ensures wide dissemination of information regarding Standing Committee meeting locations and dates and information relating to its activities;
- ensures and encourages open participation in Standing Committee meetings by all interested persons; and,
- appoints the Standing Neutral to facilitate discussions among the states, to monitor issues and to assist the Standing Committee.

Recent Activities of the Standing Committee

Q. Please provide an overview of the recent activities of the Standing Committee that led up to this filing.

A. At the November 2008 Commissioners' Forum, an issue was raised by Utah related to the performance of the Revised Protocol as compared against the forecast results at the time the Revised Protocol had been adopted. At that meeting, MSP participants reviewed a chart comparing the MSP 2005 forecast with the original MSP 2004 forecast. The chart also provided comparisons to the Rolled-In allocation methodology both with and without the Utah rate mitigation measures. The chart raised concerns that Utah's expectations when adopting the Revised Protocol - near-term costs but long-term savings for Utah customers as compared to Rolled-In - were not projected to be fulfilled. In response to this concern, at the Standing Committee Annual Meeting held in November 2008, the Company agreed to undertake a new forecast of results under the Revised Protocol using updated information from the upcoming 2008 Integrated Resource Plan which was to be filed in March 2009. The results were to be completed in sufficient time to be presented at the next annual Commissioners' Forum. As discussed in detail in the direct testimony of Mr. McDougal, the preliminary results of these studies were provided to parties on August 17, 2009.

On August 27, 2009, the Standing Neutral sent a request to parties for any new issues to be considered by the Standing Committee in preparation for the annual meeting scheduled for December 9, 2009. On September 9, 2009, several Utah parties issued a notification to MSP participants of the following issue:

> "Given review of the Company's August 17, 2009, MSP Preliminary Study Results (2009 MSP Study) and the Public Service Commission of Utah's (PSCU) December 14, 2004, Report and Order in Docket No. 02-035-04, (MSP Order) the issue we raise is whether continued use of the revised protocol and rolled-in methods with rate mitigation measures is just and reasonable for PacifiCorp's Utah jurisdiction."

Q. What action did the Standing Committee take in response to this issue?

A. The Utah issue was first discussed by the Standing Committee at a meeting held on September 10, 2009. At the conclusion of the meeting, Utah parties were asked by the Standing Committee to develop a potential solution.

Q. What was the Utah parties' potential solution?

A. At the September 24, 2009 Standing Committee meeting, Utah parties proposed a strawman solution that would eliminate seasonal and regional resource categories, limit the state resource category to demand-side management programs and state portfolio standard resource costs, and apply allocation factors for system resources to the resources formerly addressed in the seasonal, regional and state resource categories. In a nutshell, the strawman solution described a move to a Rolled-In allocation methodology.

Q. What potential solutions were considered subsequently?

A. Over the next several months of Standing Committee meetings, participants considered the Utah parties' strawman solution, together with additional solution proposals offered for consideration by other MSP participants that focused on the elements of the Revised Protocol that could be analyzed as alternative considerations to address the Utah issue. At the direction of the Standing Committee, the Company provided quantitative analysis of the various proposls to aid the Standing Committee's deliberations and considerations.

Q. When was the first opportunity to inform and update the Commissioners of the work of the Standing Committee to address the issue?

A. The Standing Committee convened a Commissioners' Forum in Portland, Oregon on April 6, 2010. At that meeting, the Standing Committee updated Commissioners generally on the activities of the Committee since the previous Commissioners' Forum in November 2008. The Commissioners were also presented with the Utah issue, together with a summarization of the analyses performed and potential solutions considered. A concern raised was that the Utah issue, if insufficiently addressed, could cause states to depart from a consistent method of cost allocation and impair integrated system planning. After some consideration of the issues and materials presented, the Commissioners directed the Standing Committee to continue progress on analyzing potential solutions to resolve the Utah issue and requested a follow-up meeting for the summer of 2010. In general, it was recognized that any solution would need to strike a balance between making progress toward fully Rolled-In allocations while maintaining a hydro endowment for Oregon and Wyoming.

Q. What was the progress of potential solutions prior to the next Commissioners' Forum?

A. The Standing Committee and participants met for an additional six meetings to continue the quantitative analyses of potential solutions to the Utah issue. As well as analyzing potential solutions, the Standing Committee and participants analyzed the potential impacts of not being able to achieve a resolution acceptable to all states. These studies, known as the control area structural separation and go-it-alone studies, were informative of the benefits of PacifiCorp continuing to operate as a single system. Progress since April 2010 was presented at the Commissioners' Forum held on June 13, 2010.

Q. What direction was received from Commissioners at the forum held on June 13, 2010?

A. At the Commissioners' Forum held on June 13, 2010, the Standing Committee updated Commissioners on the progress made since the previous meeting. The Commissioners expressed praise for the progress made and requested that the Standing Committee continue its efforts toward an acceptable resolution. An additional check-in meeting was targeted for July 2010.

After the check-in, the Standing Committee developed a summary of what the members heard as guidance from the Commissioners. The summary included the following key points:

1. All states prefer a consistent and fair cost allocation methodology that assures the Company a reasonable opportunity to recover its costs and support further system investment.

2. Utah prefers the Rolled-In allocation methodology, or results stated as a deviation from the Rolled-In allocation methodology as a viable solution alternative.
3. Oregon and Wyoming Standing Committee members have considered pre-2005 resource scenarios[1] as possible solution alternatives.

4. Both Wyoming and Oregon stressed that maintaining a hydro endowment is a critical component on any allocation methodology.

5. Utah stressed its benchmark methodology is Rolled-In and an allocation methodology should reflect Rolled-In +/- adjustments which are fixed for some future time period so as to avoid a repeat of not achieving expected forecasted results.

6. The Commissioners have agreed that the Standing Committee should work with the Company to develop an updated analysis based on Wyoming – 1 results which could be used to establish a fixed amount per year per state as a deviation from the Rolled-In allocation methodology and is net of the situs assignment of the Klamath surcharge.. The results will be presented for all years of the study and be accompanied by a disk with working spreadsheets. Assessing whether the Wyoming - 1 achieves essentially a Rolled-In result could be viewed from the perspective of treating the Klamath Settlement as Rolled-In.

Q. What actions did the Standing Committee take based on this guidance?

A. Through additional conference calls and supporting analysis, the Standing Committee reached an agreement in principle that was presented on July 26, 2010 at a final Commissioners' Forum check-in conference call. The statement provided by the Standing Committee at that meeting stated:

"Standing Committee participants of the MSP process have tentatively reached an agreement in principle changing the Revised Protocol cost allocation methodology. The initial premise for this new agreement is a Rolled-In cost allocation methodology. The changed methodology continues to identify State

[1] "Pre-2005 resource scenarios" refers to the set of resources included in the "All-Other" category of the Embedded Cost Differential calculation. This is discussed in more detail in the direct testimony of Mr. McDougal.

Resources based on cost responsibility and Regional Resources for the Hydro Endowment calculation. Besides using Rolled-In as the starting point, a significant change relates to the Hydro Endowment quantified under the Embedded Cost Differential (ECD). The ECD will be reduced and limited using a comparison based on Pre-2005 Resources. It is proposed that for 2011 through 2016, the ECD calculation will be projected and a fixed dollar amount per year deviation from Rolled-In analysis would be applied. The deviation is composed of two parts; (1) a situs adjustment charge for the Klamath Surcharge to Oregon and California, with a corresponding credit to the other states, and (2) an adjustment to reflect the Hydro Endowment ECD.

State specific concerns continue to be evaluated and discussed. For instance: In Utah this cost allocation methodology produces results close to Rolled-In so a side agreement between the Company and Utah parties will allow Utah to utilize Rolled-In cost allocation methodology for its ratemaking purposes. Forecast accuracy also continues to be evaluated by the other states, Oregon in particular, and may result in state specific measures to address the forecast risk related to fluctuations, up or down. Wyoming parties have an interest in addressing a concern about the Revised Protocol definition of State Resources."

Q. What was the outcome of the Commissioners' Forum held on July 26, 2010?

A. At the Commissioners' Forum held on July 26, 2010, the Standing Committee updated Commissioners that the group had reached an agreement in principle. Commissioners were informed that the Company hoped to file an application in each state by mid-September 2010 initiating limited amendments to the Revised Protocol that would implement the terms of the agreement in principle.

Overview of Proposed Amendments

Q. In summary, what key concerns do the proposed amendments endeavor to address?

A. As noted above, there were several overarching concerns expressed in the meetings:

- The need to move more toward a Rolled-In allocation methodology to reflect system operations while retaining the hydro endowment in some form.

- Volatility of results and unintended consequences of the ECD.
- Unpredictability of reliance on forecasts.
- Any solution must be fair to all states, and the Company must be afforded the opportunity to recover its prudently incurred costs.

Q. Are the amendments proposed by the Company and supported by the Standing Committee consistent with this agreement in principle?

A. Yes. The details are discussed in the direct testimony of Mr. McDougal.

Q. Do the amendments exclusively address the Utah issue?

A. No. The amendments also reflect an additional category of state resources called "state-specific initiatives". This addition includes emerging state-specific efforts to encourage investment in specific types of resources.

Q. Does this only include renewable resources?

A. No. The category does not limit the type of resource for which a state may seek to encourage investment.

Process for Commission Review of Application

Q. What process does the Company propose for the Commission review of this Application?

A. The Company is hopeful that the Commission will be able to complete its review of this Application within a six-month timeframe. As discussed in the Company's direct testimony, significant analysis has been undertaken and reviewed by many parties since November 2008 as the Standing Committee considered its options. However, not all interested parties were able to participate in the Standing Committee efforts. As such, the Company proposes the following illustrative schedule of milestones that would allow for discovery, rounds of testimony and hearings that would allow sufficient time for a comprehensive record to be developed upon which the Commission may base its decision:

Event	Date
PacifiCorp Application, Testimony and Exhibits	September 15, 2010
Intervenor Testimony due	Early-December 2010
PacifiCorp Rebuttal Testimony due	Early-January 2011
Public Hearing	Late-January 2011
Briefs due	Mid-February 2011
Target Date for Commission Decision	March 31, 2011

Q. Does the Company intend to continue dialogue with interested parties in each state during the proceedings?

A. Yes. As noted in the Standing Committee's statement, the Company intends to seek an agreement with Utah parties related to the use of the Rolled-In allocation methodology and to work with Oregon parties to address forecast risk. The Company will also work to address any additional concerns that arise during the proceedings. It will be imperative that any state-specific agreements do not undermine the intent of the 2010 Protocol to allow PacifiCorp the reasonable opportunity to recover 100 percent of its prudently incurred costs.

Processes subsequent to amendment adoption

Q. Assuming that the four state Commissions acknowledge the amendments and adopt the 2010 Protocol, what ongoing processes does the Company envision related to the 2010 Protocol?

A. As reflected in the 2010 Protocol, the Company is not proposing any changes to the ongoing Standing Committee function at this time. Although the elements of the 2010 Protocol are designed to minimize controversy and provide predictability through calendar year 2016, there are always emerging issues on which it is valuable for states to continue to engage in discussions.

Q. What does the Company envision as a process to address allocation issues post-2016?

A. The process would likely be similar to the one just followed. For example, the post-2016 issues would likely first be reviewed at the 2015 Standing Committee annual meeting. From that review, the Standing Committee would agree on appropriate next steps as far as issue identification and analysis. Standing Committee efforts would need to be designed to culminate in time for formal commission proceedings to occur with decisions well in advance of January 1, 2017. It is also possible that the states would agree to extend the terms of the 2010 Protocol to apply beyond calendar year 2016.

Introduction of Witnesses

Q. Please introduce the Company's other witnesses and provide a brief description of their testimony.

A. They are:

- Mr. Steven R. McDougal addresses the calculation and implementation of the 2010 Protocol allocation methodology and presents the revenue requirement analyses undertaken at the request of the Standing Committee, and
- Mr. Gregory N. Duvall presents the net power cost (NPC) studies used to support the 2010 Protocol revenue requirement analysis and to inform of the Standing Committee's consideration of options.

Q. Does this conclude your direct testimony?

A. Yes.

Case No. PAC-E-10-09
Exhibit No. 1
Witness: Andrea L. Kelly

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Andrea L. Kelly

2010 Protocol, including Appendices A to F

September 2010

2010 Protocol

I. Introduction

This 2010 PacifiCorp Inter-Jurisdictional Cost Allocation Protocol (2010 Protocol) is the result of continuing discussions that have occurred among representatives of PacifiCorp, Commission staff members and other interested parties from Utah, Oregon, Wyoming, and Idaho regarding issues arising from the previously adopted Revised Protocol, and the Company's status as a multi-jurisdictional utility.

PacifiCorp commits that it will continue to plan and operate its generation and transmission system on a six-State integrated basis in a manner that achieves a least cost/least risk Resource portfolio for its customers.

The 2010 Protocol describes regulatory policies, which, if utilized by all States for rate proceedings filed prior to January 1, 2017, should afford PacifiCorp a reasonable opportunity to recover all of its prudently incurred expenses and investments and earn its authorized rate of return. The assignment of a particular expense or investment, or allocation of a share of an expense or investment, to a State pursuant to the 2010 Protocol is not intended to, and should not, prejudge the prudence of those costs. Nothing in the 2010 Protocol shall abridge any State's right and/or obligation to establish fair, just and reasonable rates based upon the law of that State and the record established in rate proceedings conducted by that State. Parties who have supported the ratification of the 2010 Protocol do so in the belief that it will continue to achieve a solution to multistate issues that is in the public interest. However, a party's support of the 2010 Protocol is not intended in any manner to negate the necessary flexibility of the regulatory process to deal with changed or unforeseen circumstances, and a party's support of the 2010 Protocol will not bind or be used against that party in the event that unforeseen or changed circumstances cause that party to conclude, in good faith, that the 2010 Protocol no longer produces results that are just, reasonable and in the public interest. Support of the 2010 Protocol shall not be deemed to constitute an acknowledgement by any party of the validity or invalidity of any particular method, theory or principle of regulation, cost recovery, cost of service or rate design and no party shall be deemed to have agreed that any particular method, theory or principle of regulation, cost recovery, cost of service or rate design employed in the 2010 Protocol is appropriate for resolving any other issues.

The 2010 Protocol describes how the costs and wholesale revenues associated with PacifiCorp's generation, transmission and distribution system will be assigned or allocated among its six-State jurisdictions for purposes of establishing its retail rates.

Definitions of terms that are capitalized in the 2010 Protocol are set forth in Appendix A.

A table identifying the allocation factor to be applied to each component of PacifiCorp's revenue requirement calculation is included as Appendix B.

The algebraic derivation of each allocation factor is contained in Appendix C.

A description and numeric example of how Special Contracts and related discounts will be reflected in rates is set forth in Appendix D.

The fixed and levelized Embedded Cost Differential (ECD) amounts, that will be included in filings made through December 31, 2016, are set forth in Appendix E.

Each State's allocated share of each Mid-Columbia Contract and the method for calculating the shares is set forth in Appendix F.

II. Proposed Effective Date

The 2010 Protocol will and apply to all PacifiCorp rate proceedings filed prior to January 1, 2017.

III. Classification of Resource Costs

All Resource Fixed Costs, Wholesale Contracts and Short-term Purchases and Sales will be classified as 75 percent Demand-Related and 25 percent Energy-Related. All costs associated with Non-Firm Purchases and Sales will be classified as 100 percent Energy-Related.

IV. Allocation of Resource Costs and Wholesale Revenues

Resources will be assigned to one of three categories for inter-jurisdictional cost allocation purposes:

A. Regional Resources,

B. State Resources, or

C. System Resources.

There are two types of Regional Resource and four types of State Resources. The remainder are System Resources which constitute the substantial majority of PacifiCorp's Resources. Costs associated with each category and type of Resource will be allocated on the following basis:

A. Regional Resources

Costs associated with Regional Resources will be assigned and allocated as follows:

1. Hydro-Endowment.

a. Owned Hydro Embedded Cost Differential Adjustment. The Owned Hydro Embedded Cost Differential Adjustment is calculated as follows:

- The Forecasted Embedded Costs – Hydro-Electric Resources, less the Forecasted Embedded Costs – Pre-2005 Resources, multiplied by the normalized MWh's of output from the Hydro-Electric Resources.
- The calculation is made using forecasted information contained in the Company's Baseline Study (finalized in March 2010) for calendar years 2011 through 2016.
- The forecasted differential is allocated on the DGP factor and the inverse amount is allocated on the SG factor to compute State specific amounts for calendar years 2011 through 2016.
- The net present value of the forecasted differential by State is set at a fixed dollar level that will be used for all PacifiCorp rate proceedings filed prior to January 1, 2017.

b. Mid-Columbia Contract Embedded Cost Differential Adjustment. The Mid-Columbia Contract Embedded Cost Differential Adjustment is calculated as follows:

- The Forecasted Mid-Columbia Contracts Costs, less the Forecasted Embedded Costs – Pre-2005 Resources, multiplied by the normalized MWh's of output from the Mid-Columbia Contracts (Mid-C less All Other).

- The calculation is made using forecasted information contained in the Company's Baseline Study (finalized in March 2010) for calendar years 2011 through 2016.
- The forecasted allocation of Mid-Columbia Contracts to each State is established pursuant to Appendix F. The forecasted Mid-Columbia differential is allocated on the MC factor and the inverse amount is allocated on the SG factor to compute State specific amounts for calendar years 2011 through 2016.
- The net present value of the forecasted differential by State is set at a fixed dollar level that will be used for all PacifiCorp rate proceedings filed prior to January 1, 2017.

The results of the Owned Hydro Embedded Cost Differential calculation and the Mid-Columbia Contract Embedded Cost Differential calculation are added together and a levelized annual value for the calendar years 2011 through 2016 time period is calculated. The levelized Hydro Endowment is fixed for purposes of ratemaking for that time period.

2. <u>Klamath Hydroelectric Settlement Agreement (KHSA).</u> As part of future ratemaking proceedings, the Company will include the full impact of the KHSA as a system cost in unadjusted results.

a. Klamath Dam Removal Surcharge Adjustment. The Klamath Dam Removal Surcharge is re-allocated to Oregon (92 percent) and California (8 percent) as follows:

- Each State's initial allocated share of the Klamath Dam Removal Surcharge is reversed and assigned to Oregon and California on a situs basis. The calculation is made using forecasted information contained in the Company's Baseline Study (finalized in March 2010) for calendar years 2011 through 2016.
- The net present value of the forecasted adjustment by State is set at a fixed dollar level that will be used for all PacifiCorp rate proceedings filed prior to January 1, 2017. The levelized annual value for the calendar years 2011 through 2016 time period will be used for purposes of ratemaking for that time period.

B. State Resources

Costs associated with the four types of State Resources will be assigned as follows:

1. Demand-Side Management Programs: Costs associated with Demand-Side Management Programs will be assigned on a situs basis to the State in which the investment is made. Benefits from these programs, in the form of reduced consumption and contribution to peak, will be reflected through time in the Load-Based Dynamic Allocation Factors.

2. Portfolio Standards: Costs associated with Resources acquired pursuant to a State Portfolio Standard, which exceed the costs PacifiCorp would have otherwise incurred, will be assigned on a situs basis to the State adopting the standard.

3. New Qualifying Facilities (QF) Contracts: Costs associated with any New QF Contract, which exceed the costs PacifiCorp would have otherwise incurred acquiring Comparable Resources, will be assigned on a situs basis to the State approving such contract.

4. State-Specific Initiatives: Costs associated with Resources acquired pursuant to a State-specific initiative will be assigned on a situs basis to the State adopting the initiative. This includes the costs of incentive programs, net-metering tariffs, feed-in tariffs, capacity standard programs, electric vehicle programs and the acquisition of renewable energy certificates.

C. System Resources

All Resources that are not Regional Resources or State Resources are System Resources. Generally, all Fixed Costs associated with System Resources and all costs incurred under Wholesale Contracts will be allocated based upon the SG Factor. Generally, all Variable Costs associated with System Resources will be allocated based upon the SE Factor. Revenues received by the Company pursuant to Wholesale Contracts will be allocated based upon the SG Factor. A complete description of the allocation factors to be utilized is set forth in Appendix B.

D. Load Growth

At the direction of the MSP Standing Committee, the Company and parties will continue to analyze and quantify potential cost shifts related to faster-growing States.[1] In addition, the MSP Standing Committee will track key factors including actual relative growth rates, forecast relative growth rates, costs of new Resources compared to costs of existing Resources, and other factors deemed relevant to any potential load growth-related issues.

V. Refunctionalization and Allocation of Transmission Costs and Revenues

If the Company is required to refunctionalize assets that are currently functionalized as "transmission" to "distribution", the cost responsibility for any such refunctionalized assets will be assigned to the State where they are located. Any refunctionalization will be implemented under the guidance of the MSP Standing Committee.

Costs associated with transmission assets, and firm wheeling expenses and revenues, will be classified as 75 percent Demand-Related, 25 percent Energy-Related and allocated among the States based upon the SG (System Generation) factor. Non-firm wheeling expenses and revenues will be allocated among the States based upon the SE Factor.

[1] This issue will be monitored through studies that compute the costs allocated to each State for two cases: (a) with currently projected load growth together with a least-cost, least-risk mix of Resource additions to meet that growth and (b) with the fastest-growing State growing at the average growth projected for the remaining States, again with a least-cost, least-risk mix of Resource additions.

VI. Assignment of Distribution Costs

All distribution-related expenses and investment that can be directly assigned will be directly assigned to the state where they are located. Those costs that cannot be directly assigned will be allocated among States consistent with the factors set forth in Appendix B.

VII. Allocation of Administrative and General Costs

Administrative and general costs, costs of General Plant and costs of Intangible Plant will be allocated among States consistent with the factors set forth in Appendix B.

VIII. Allocation of Special Contracts

Revenues associated with Special Contracts will be included in State revenues and loads of Special Contract customers will be included in all Load-Based Dynamic Allocation Factors. Special Contracts may or may not include Customer Ancillary Service Contract attributes. In recognition that Special Contracts may take different forms, Appendix D provides a written description and numeric example of the regulatory treatment of Special Contracts and associated discounts.

IX. Allocation of Gain or Loss from Sale of Resources or Transmission Assets

Any loss or gain from the sale of a Resource (other than a Freed-Up Resource) or a transmission asset will be allocated among States based upon the allocation factor used to allocate the Fixed Costs of the Resource or the transmission asset at the time of its sale. Each Commission will determine the appropriate allocation of loss or gain allocated to that State as between State customers and PacifiCorp shareholders.

X. Implementation of Direct Access Programs

A. Allocation of Costs and Benefits of Freed-Up Resources

1. Loads lost to Direct Access – Where the Company is required to continue to plan for the load of Direct Access Customers, such load will be included in Load-Based Dynamic Allocation Factors for all Resources.
2. Loads of customers permanently choosing Direct Access or permanently opting out of New Resources – Where the Company is no longer required to plan for the load of customers who permanently choose direct access or permanently opt out of New Resources, such loads will be included in Load-Based Dynamic Allocation Factors for all Existing Resources but will not be included in Load-Based Dynamic Allocation Factors for New Resources acquired after the election to permanently choose Direct Access or opt out of New Resources. An effective date for this process will be established at such time as customers permanently choose Direct Access or opt out, and this process will be implemented under the guidance of the MSP Standing Committee.
3. In each State with Direct Access Customers, an additional step will take place for ratemaking purposes to establish a value or cost (which could include a transfer of Freed-Up Resources between customer classes within a State) resulting from the departure of the departing load; other States do not implement the second step.

B. Freed-Up Resource Sale Approval

Any proposed sale of a Freed-Up Resource for purposes of calculating transition charges or credits will be subject to applicable regulatory review and approval based upon a "no-harm" standard. States implementing Direct Access Programs that involve the sale of Freed-Up Resources will endeavor to propose a method for allocating the gain or loss on a sale to Direct Access Customers in a manner that satisfies the "no-harm" standard in respect to customers in the other States. The parties agree that they will not advocate a sale of Freed-Up Resources to be consummated if the proposed allocation of the gain or loss from the sale would cause the Company to distribute more than the total gain on a sale or recover less than the full amount of the total loss on a sale.

C. Allocation of Revenues and Costs from Direct Access Purchases and Sales

Revenues and costs from Direct Access Purchases and Sales will be assigned situs to the State where the Direct Access Customers are located and will not be included in Net Power Costs.

XI. Loss or Increase in Load

Any loss or increase in retail load occurring as a result of condemnation or municipalization, sale or acquisition of new service territory which involves less than five percent of system load, realignment of service territories, changes in economic conditions or gain or loss of large customers will be reflected in changes in Load-Based Dynamic Allocation Factors. The allocation of costs and benefits arising from merger, sale and acquisition transactions proposed by the Company involving more than five percent of system load will be dealt with on a case-by-case basis in the course of Commission approval proceedings.

XII. Commission Regulation of Resources

PacifiCorp shall plan and acquire new Resources on a system-wide least cost, least risk basis. Prudently incurred investments in Resources will be reflected in rates consistent with the laws and regulations in each State.

XIII. Sustainability of 2010 Protocol

A. Issues of Interpretation

If questions of interpretation of the 2010 Protocol arise during rate proceedings and/or audits of results of PacifiCorp's operations, parties will attempt to resolve them with reference to the intent of the parties who have supported the ratification of the 2010 Protocol.

B. MSP Standing Committee

1. The existing MSP Standing Committee will continue to be organized consisting of one member or delegate of each Commission. The chair of the MSP Standing Committee will be elected each year by the members of the Committee.
2. The MSP Standing Committee will appoint a Standing Neutral, at the Company's expense, to facilitate discussions among States, monitor issues and assist the MSP Standing Committee.
3. At least once during each calendar year, the Standing Neutral will convene a meeting of the MSP Standing Committee and interested parties from all States for the purpose of discussing and monitoring emerging inter-jurisdictional issues facing the Company and its customers. The meetings will be open to all interested parties.

4. The MSP Standing Committee will consider possible amendments to the 2010 Protocol that would be equitable to PacifiCorp customers in all States and to the Company. The MSP Standing Committee will have discretion to determine how best to encourage consensual resolution of issues arising under the 2010 Protocol. Its actions may include, but will not be limited to: a) appointing a committee of interested parties to study an issue and make recommendations, or b) retaining (at the Company's expense) one or more disinterested parties to make advisory findings on issues of fact arising under the 2010 Protocol.

5. The work of the MSP Standing Committee will be supported by sound technical analysis. A party supporting ratification of the 2010 Protocol will work in good faith to address issues being considered by the MSP Standing Committee.

C. 2010 Protocol Amendments

Proposed amendments to the 2010 Protocol will be submitted by PacifiCorp to each Commission for ratification. The 2010 Protocol will only be deemed to have been amended if each of the Commissions who have previously ratified the 2010 Protocol ratifies the amendment. PacifiCorp will not seek Commission ratification of any amendment to the 2010 Protocol unless and until it has provided interested parties with at least six months advance notice of its intent to do so and endeavored to obtain consensus regarding its proposed amendment. A party's initial support or acceptance of the 2010 Protocol will not bind or be used against that party in the event that unforeseen or changed circumstances cause that party to conclude that the 2010 Protocol no longer produces just and reasonable results. Prior to departing from the terms of the 2010 Protocol, consistent with their legal obligations, Commissions and parties will endeavor to cause their concerns to be presented at meetings of the MSP Standing Committee and interested parties from all States in an attempt to achieve consensus on a proposed resolution of those concerns.

D. Interdependency among Commission Approvals

The 2010 Protocol has been developed by the parties as an integrated, inter-dependent, organic whole. Therefore, final ratification of the 2010 Protocol by any of the Commissions of Oregon, Utah, Wyoming and Idaho, is expressly conditioned upon similar ratification of the 2010 Protocol by the other mentioned Commissions, without any deletion or alteration of a material term, or the addition of other material terms or conditions. Upon any rejection of the 2010 Protocol, or any material deletion, alteration, or addition to its terms, by any one or more of the four Commissions, the Commissions who have previously conditionally adopted the 2010 Protocol shall initiate proceedings to determine whether they should reaffirm their prior ratification of the 2010 Protocol, notwithstanding the action of the other Commission or Commissions. The 2010 Protocol shall only be in effect for a State upon final ratification by its Commission. The Company will continue to bear the risk of inconsistent allocation methods among the States.

APPENDIX A

2010 Protocol - Appendix A

Defined Terms

For purposes of this 2010 Protocol, the following terms will have the following meanings:

"2010 Protocol" means this 2010 PacifiCorp Inter-Jurisdictional Cost Allocation Protocol.

"Baseline Study" means the calculation of the Company's projected revenue requirement for calendar years 2010 through 2019 and the corresponding inter-jurisdictional allocation. The Baseline Study was prepared in March 2010 and was designed to facilitate States' assessment of the ongoing reasonableness of the Revised Protocol.

"Coincident Peak" means the hour each month that the combined demand of all PacifiCorp retail customers is greatest. In States using an historic test period, Coincident Peak is based upon actual, metered load data. In States using future test periods, Coincident Peak is based upon forecasted loads.

"Company" means PacifiCorp.

"Commission" means a utility regulatory commission in a State.

"Comparable Resource" means Resources with similar capacity factors, start-up costs, and other output and operating characteristics.

"Customer Ancillary Service Contracts" means contracts between the Company and a retail customer pursuant to which the Company pays the customer for the right to curtail service so as to lower the costs of operating the Company's system.

"Demand-Related Costs" means capital and other Fixed Costs incurred by the Company in order to be prepared to meet the maximum demand imposed upon its system.

"Demand-Side Management Programs" means programs intended to reduce electricity use through activities or programs that promote electric energy efficiency or conservation, more efficient management of electric energy loads, or reductions in peak demand.

"Direct Access Customers" means retail electricity consumers located in PacifiCorp's service territory that either: a) purchase electricity directly from a supplier other than PacifiCorp pursuant to a Direct Access Program or b) elect to have all or a portion of the electricity they purchase from PacifiCorp priced based upon market prices rather than the Company's traditional cost-of-service rate. If a State implements a Direct Access Program pursuant to which Freed-Up Resources are transferred between customer classes, such transfers shall be considered Direct Access Purchases and Sales.

"Direct Access Program" means a law or regulation that permits retail consumers located in PacifiCorp's service territory to purchase electricity directly from a supplier other than PacifiCorp.

"Direct Access Purchases and Sales" means Wholesale Contracts and Short-Term Purchases and Sales entered into by PacifiCorp either to supply customers who have become Direct Access Customers or to dispose of Freed-Up Resources.

"Energy-Related Costs" means costs, such as fuel costs that vary with the amount of energy delivered by the Company to its customers during any hour plus any portion of Fixed Costs that have been deemed to have been incurred by the Company in order to meet its energy requirements.

"Existing Resources" means Resources whose costs were committed to prior to Direct Access Customers making an election to permanently forego being served by the Company at a cost-of-service rate.

"FERC" means the Federal Energy Regulatory Commission.

"Fixed Costs" means costs incurred by the Company that do not vary with the amount of energy delivered by the Company to its customers during any hour.

"Forecasted Embedded Costs – Hydro-Electric Resources" means PacifiCorp's total forecasted production costs contained in the Company's Baseline Study, for calendar years 2011 through 2016, expressed in dollars per MWh, associated with Hydro-Electric Resources as recorded in the FERC Accounts listed in Appendix E to the 2010 Protocol.

"Forecasted Embedded Costs – Pre-2005 Resources" means PacifiCorp's total forecasted production costs of Pre-2005 Resources contained in the Company's Baseline Study, for calendar years 2011 through 2016, expressed in dollars per MWh, other than costs associated with Hydro-Electric Resources, and Mid-Columbia Contracts, as recorded in the FERC Accounts listed in Appendix E to the 2010 Protocol.

"Forecasted Mid-Columbia Contract Costs" means the total forecasted net costs incurred by PacifiCorp contained in the Company's Baseline Study, for calendar years 2011 through 2016, expressed in dollars per MWh, under the Mid-Columbia Contracts.

"Freed-Up Resources" means Resources made available to the Company as a result of its customers becoming Direct Access Customers.

"General Plant" means capital investment included in FERC accounts 389 through 399.

"Grant County" means Public Utility District No. 2 of Grant County, Washington

"Hydro-Electric Resources" means Company-owned hydro-electric plants located in Oregon, Washington or California.

"Intangible Plant" means capital investment included in FERC accounts 301 through 303.

"Klamath Dam Removal Surcharge" means the tariffs collected from customers in California and Oregon for the purpose of providing funding to remove specific Klamath River dams, as detailed in the Klamath Hydroelectric Settlement Agreement.

"Klamath Hydroelectric Settlement Agreement" means the Klamath Hydroelectric Settlement Agreement executed on February 18, 2010 for the purpose of resolving specific FERC relicensing proceedings by establishing a process for potential facilities removal and operation of hydroelectric projects until that time.

"Load-Based Dynamic Allocation Factor" means an allocation factor that is calculated using States' monthly energy usage and/or States' contribution to monthly system Coincident Peak.

"Mid-Columbia Contracts" means the Power Sales Contract with Grant County dated May 22, 1956; the Power Sales Contract with Grant County dated June 22, 1959;the Priest Rapids Project Product Sales Contract with Grant County dated December 31, 2001; the Additional Products Sales Agreement with Grant County dated December 31, 2001; the Priest Rapids Project Reasonable Portion Power Sales Contract with Grant County dated December 31, 2001; the Power Sales Contract with Douglas County PUD dated September 18, 1963; the Power Sales Contract with Chelan County PUD dated November 14, 1957 and all successor contracts thereto.

"Net Power Costs" means PacifiCorp's fuel and wheeling expenses and costs and revenues associated with Wholesale Contracts, Seasonal Contracts, Short-Term Purchases and Sales and Non-Firm Purchases and Sales.

"New QF Contracts" means Qualifying Facility Contracts that are entered into subsequent to September 15, 2010.

"New Resources" means Resources that are not Existing Resources as established pursuant to Paragraph XA2 of the 2010 Protocol.

"Non-Firm Purchases and Sales" means transactions at wholesale that are not Wholesale Contracts, Seasonal Contracts, Short-Term Purchases and Sales or Direct Access Purchases and Sales.

"Portfolio Standard" means a State law or regulation that requires PacifiCorp to acquire: (a) a particular type of Resource, (b) a particular quantity of Resources, (c) Resources in a prescribed manner or (d) Resources located in a particular geographic area.

"Pre-2005 Resources" means Resources (other than Mid-Columbia Contracts and Hydro-Electric Resources) that were part of the Company's integrated system prior to January 1, 2005.

"Qualifying Facility Contracts" means contracts to purchase the output of small power production or cogeneration facilities developed under the Public Utility Regulatory Policies Act of 1978 (PURPA) and related State laws and regulations.

"Resources" means Company-owned and leased generating plants and mines, Wholesale Contracts, Seasonal Contracts, Short-Term Purchases and Sales and Non-firm Purchases and Sales.

"Short-Term Purchases and Sales" means physical or financial contracts pursuant to which PacifiCorp purchases, sells or exchanges firm power at wholesale and Customer Ancillary Service Contracts that are less than one year in duration.

"Special Contract" means a contract entered between PacifiCorp's and one of its retail customers with prices, term and conditions different from otherwise-applicable tariff rates. Special Contracts may provide for a discount to reflect Customer Ancillary Services Contract attributes.

"Special Contract Ancillary Service Discounts" means discounts from otherwise applicable rates provided for in Special Contracts.

"Standing Neutral" means an independent party, with experience in electric utility ratemaking, retained by the MSP Standing Committee to facilitate discussions among States, monitor issues and assist the MSP Standing Committee as required.

"State Resources" means Resources whose costs are assigned to a single State to accommodate State-specific policy preferences.

"System Resources" means Resources that are not Regional Resources, State Resources or Direct Access Purchases and Sales and whose associated costs and revenues are allocated among all States on a dynamic basis.

"State" means Utah, Oregon, Wyoming, Idaho, Washington or California.

"Variable Costs" means costs incurred by the Company that vary with the amount of energy delivered by the Company to its customers during any hour.

"Wholesale Contracts" means physical or financial contracts pursuant to which PacifiCorp purchases, sells or exchanges firm power at wholesale and Customer Ancillary Service Contracts.

APPENDIX B

2010 Protocol - Appendix B
Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
Sales to Ultimate Customers			
440	Residential Sales		
		Direct assigned - Jurisdiction	S
442	Commercial & Industrial Sales		
		Direct assigned - Jurisdiction	S
444	Public Street & Highway Lighting		
		Direct assigned - Jurisdiction	S
445	Other Sales to Public Authority		
		Direct assigned - Jurisdiction	S
448	Interdepartmental		
		Direct assigned - Jurisdiction	S
447	Sales for Resale		
		Direct assigned - Jurisdiction	S
		Non-Firm	SE
		Firm	SG
449	Provision for Rate Refund		
		Direct assigned - Jurisdiction	S
			SG
Other Electric Operating Revenues			
450	Forfeited Discounts & Interest		
		Direct assigned - Jurisdiction	S
451	Misc Electric Revenue		
		Direct assigned - Jurisdiction	S
		Other - Common	SO
454	Rent of Electric Property		
		Direct assigned - Jurisdiction	S
		Common	SG
		Other - Common	SO
456	Other Electric Revenue		
		Direct assigned - Jurisdiction	S
		Wheeling Non-firm, Other	SE
		Common	SO
		Wheeling - Firm, Other	SG
		Customer Related	CN
Miscellaneous Revenues			
41160	Gain on Sale of Utility Plant - CR		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		General Office	SO

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT		DESCRIPTION	ALLOCATION FACTOR
41170	Loss on Sale of Utility Plant		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		General Office	SO
4118	Gain from Emission Allowances		
		SO2 Emission Allowance sales	SE
41181	Gain from Disposition of NOX Credits		
		NOX Emission Allowance sales	SE
421	(Gain) / Loss on Sale of Utility Plant		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		General Office	SO
Miscellaneous Expenses			
4311	Interest on Customer Deposits		
		Utah Customer Service Deposits	CN
		Direct assigned - Jurisdiction	S
Steam Power Generation			
500, 502, 504-514	Operation Supervision & Engineering		
		Steam Plants	SG
501	Fuel Related		
		Steam Plants	SE
503	Steam From Other Sources		
		Steam Royalties	SE
Nuclear Power Generation			
517 - 532	Nuclear Power O&M		
		Nuclear Plants	SG
Hydraulic Power Generation			
535 - 545	Hydro O&M		
		Pacific Hydro	SG
		East Hydro	SG
Other Power Generation			
546, 548-554	Operation Super & Engineering		
		Other Production Plant	SG
547	Fuel		
		Other Fuel Expense	SE
Other Power Supply			
555	Purchased Power		
		Direct assigned - Jurisdiction	S
		Firm	SG
		Non-firm	SE
		100 MW Hydro Extension	SG

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
556	System Control & Load Dispatch		
		Other Expenses	SG
557	Other Expenses		
		Direct assigned - Jurisdiction	S
		Other Expenses	SG
	2010 Protocol Adjustments		
		Hydro Endowment	S
		Klamath Dam Removal Surcharge	S
		Klamath Dam Removal Surcharge Re-allocation	S
TRANSMISSION EXPENSE			
560-564, 566-573	Transmission O&M		
		Transmission Plant	SG
565	Transmission of Electricity by Others		
		Firm Wheeling	SG
		Non-Firm Wheeling	SE
DISTRIBUTION EXPENSE			
580 - 598	Distribution O&M		
		Direct assigned - Jurisdiction	S
		Other Distribution	SNPD
CUSTOMER ACCOUNTS EXPENSE			
901 - 905	Customer Accounts O&M		
		Direct assigned - Jurisdiction	S
		Total System Customer Related	CN
CUSTOMER SERVICE EXPENSE			
907 - 910	Customer Service O&M		
		Direct assigned - Jurisdiction	S
		Total System Customer Related	CN
SALES EXPENSE			
911 - 916	Sales Expense O&M		
		Direct assigned - Jurisdiction	S
		Total System Customer Related	CN
ADMINISTRATIVE & GEN EXPENSE			
920-935	Administrative & General Expense		
		Direct assigned - Jurisdiction	S
		Customer Related	CN
		General	SO
		FERC Regulatory Expense	SG
DEPRECIATION EXPENSE			
403SP	Steam Depreciation		
		Steam Plants	SG
403NP	Nuclear Depreciation		
		Nuclear Plant	SG

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
403HP	Hydro Depreciation		
		Pacific Hydro	SG
		East Hydro	SG
403OP	Other Production Depreciation		
		Other Production Plant	SG
403TP	Transmission Depreciation		
		Transmission Plant	SG
403	Distribution Depreciation Direct assigned - Jurisdiction		
		Land & Land Rights	S
		Structures	S
		Station Equipment	S
		Storage Battery Equipment	S
		Poles & Towers	S
		OH Conductors	S
		UG Conduit	S
		UG Conductor	S
		Line Trans	S
		Services	S
		Meters	S
		Inst Cust Prem	S
		Leased Property	S
		Street Lighting	S
403GP	General Depreciation		
		Distribution	S
		Steam Plants	SG
		Mining	SE
		Pacific Hydro	SG
		East Hydro	SG
		Transmission	SG
		Customer Related	CN
		General SO	SO
403MP	Mining Depreciation		
		Remaining Mining Plant	SE
AMORTIZATION EXPENSE			
404GP	Amort of LT Plant - Capital Lease Gen		
		Direct assigned - Jurisdiction	S
		General	SO
		Customer Related	CN
404SP	Amort of LT Plant - Cap Lease Steam		
		Steam Production Plant	SG
404IP	Amort of LT Plant - Intangible Plant		
		Distribution	S
		Production, Transmission	SG
		General	SO
		Mining Plant	SE
		Customer Related	CN

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
404MP	Amort of LT Plant - Mining Plant		
		Mining Plant	SE
404HP	Amortization of Other Electric Plant		
		Pacific Hydro	SG
		East Hydro	SG
405	Amortization of Other Electric Plant		
		Direct assigned - Jurisdiction	S
406	Amortization of Plant Acquisition Adj		
		Direct assigned - Jurisdiction	S
		Production Plant	SG
407	Amort of Prop Losses, Unrec Plant, etc		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Trojan	TROJP
Taxes Other Than Income			
408	Taxes Other Than Income		
		Direct assigned - Jurisdiction	S
		Property	GPS
		System Taxes	SO
		Misc Energy	SE
		Misc Production	SG
DEFERRED ITC			
41140	Deferred Investment Tax Credit - Fed		
		ITC	DGU
41141	Deferred Investment Tax Credit - Idaho		
		ITC	DGU
Interest Expense			
427	Interest on Long-Term Debt		
		Direct assigned - Jurisdiction	S
		Interest Expense	SNP
428	Amortization of Debt Disc & Exp		
		Interest Expense	SNP
429	Amortization of Premium on Debt		
		Interest Expense	SNP
431	Other Interest Expense		
		Interest Expense	SNP
432	AFUDC - Borrowed		
		AFUDC	SNP

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT		DESCRIPTION	ALLOCATION FACTOR
Interest & Dividends			
419	Interest & Dividends		
		Interest & Dividends	SNP
DEFERRED INCOME TAXES			
41010	Deferred Income Tax - Federal-DR		
		Direct assigned - Jurisdiction	S
		Electric Plant in Service	DITEXP
		Pacific Hydro	SG
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Property Tax related	GPS
		Miscellaneous	SNP
		Trojan	TROJD
		Distribution	SNPD
		Mining Plant	SE
		Bad Debt	BADDEBT
		Tax Depreciation	TAXDEPR
41011	Deferred Income Tax - State-DR		
		Direct assigned - Jurisdiction	S
		Electric Plant in Service	DITEXP
		Pacific Hydro	SG
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Property Tax related	GPS
		Miscellaneous	SNP
		Trojan	TROJD
		Distribution	SNPD
		Mining Plant	SE
		Bad Debt	BADDEBT
		Tax Depreciation	TAXDEPR
41110	Deferred Income Tax - Federal-CR		
		Direct assigned - Jurisdiction	S
		Electric Plant in Service	DITEXP
		Pacific Hydro	SG
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Property Tax related	GPS
		Miscellaneous	SNP
		Trojan	TROJD
		Distribution	SNPD
		Mining Plant	SE
		Contributions in aid of construction	CIAC
		Production, Other	SGCT
		Book Depreciation	SCHMDEXP

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT		DESCRIPTION	ALLOCATION FACTOR
41111	Deferred Income Tax - State-CR		
		Direct assigned - Jurisdiction	S
		Electric Plant in Service	DITEXP
		Pacific Hydro	SG
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Property Tax related	GPS
		Miscellaneous	SNP
		Trojan	TROJD
		Distribution	SNPD
		Mining Plant	SE
		Contributions in aid of construction	CIAC
		Production, Other	SGCT
		Book Depreciation	SCHMDEXP
SCHEDULE - M ADDITIONS			
SCHMAF	Additions - Flow Through		
		Direct assigned - Jurisdiction	S
SCHMAP	Additions - Permanent		
		Direct assigned - Jurisdiction	S
		Mining related	SE
		General	SO
		Production / Transmission	SG
SCHMAT	Additions - Temporary		
		Direct assigned - Jurisdiction	S
		Contributions in aid of construction	CIAC
		Miscellaneous	SNP
		Trojan	TROJD
		Pacific Hydro	SG
		Mining Plant	SE
		Production, Transmission	SG
		Property Tax	GPS
		General	SO
		Depreciation	SCHMDEXP
		Distribution	SNPD
		Production, Other	SGCT
SCHEDULE - M DEDUCTIONS			
SCHMDF	Deductions - Flow Through		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Pacific Hydro	SG
SCHMDP	Deductions - Permanent		
		Direct assigned - Jurisdiction	S
		Mining Related	SE
		Miscellaneous	SNP
		General	SO

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT		DESCRIPTION	ALLOCATION FACTOR
SCHMDT	Deductions - Temporary		
		Direct assigned - Jurisdiction	S
		Bad Debt	BADDEBT
		Miscellaneous	SNP
		Pacific Hydro	SG
		Mining related	SE
		Production, Transmission	SG
		Property Tax	GPS
		General	SO
		Depreciation	TAXDEPR
		Distribution	SNPD
		Customer Related	CN
State Income Taxes			
40911		State Income Taxes	S
		(Internal calculation using blended statutory state and local income tax rate)	
40910		FIT True-up	S
40910		Wyoming Wind Tax Credit	SG
Steam Production Plant			
310 - 316			
		Steam Plants	SG
Nuclear Production Plant			
320-325			
		Nuclear Plant	SG
Hydraulic Plant			
330-336			
		Pacific Hydro	SG
		East Hydro	SG
Other Production Plant			
340-346			
		Other Production Plant	SG
TRANSMISSION PLANT			
350-359			
		Transmission Plant	SG
DISTRIBUTION PLANT			
360-373			
		Direct assigned - Jurisdiction	S

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
GENERAL PLANT			
389 - 398			
		Distribution	S
		Pacific Hydro	SG
		East Hydro	SG
		Production / Transmission	SG
		Customer Related	CN
		General	SO
		Mining	SE
399	Coal Mine		
		Remaining Mining Plant	SE
399L	WIDCO Capital Lease		
		WIDCO Capital Lease	SE
1011390	General Capital Leases		
		Direct assigned - Jurisdiction	S
		General	SO
		Production / Transmission	SG
INTANGIBLE PLANT			
301	Organization		
		Direct assigned - Jurisdiction	S
302	Franchise & Consent		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
303	Miscellaneous Intangible Plant		
		Distribution	S
		Pacific Hydro	SG
		East Hydro	SG
		Production / Transmission	SG
		Customer Related	CN
		General	SO
		Mining	SE
303	Less Non-Utility Plant		
		Direct assigned - Jurisdiction	S
Rate Base Additions			
105	Plant Held For Future Use		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Mining Plant	SE
114	Electric Plant Acquisition Adjustments		
		Direct assigned - Jurisdiction	S
		Production Plant	SG
115	Accum Provision for Asset Acquisition Adjustments		
		Direct assigned - Jurisdiction	S
		Production Plant	SG

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
120	Nuclear Fuel		
		Nuclear Fuel	SE
124	Weatherization		
		Direct assigned - Jurisdiction	S
		General	SO
182W	Weatherization		
		Direct assigned - Jurisdiction	S
186W	Weatherization		
		Direct assigned - Jurisdiction	S
151	Fuel Stock		
		Steam Production Plant	SE
152	Fuel Stock - Undistributed		
		Steam Production Plant	SE
25316	DG&T Working Capital Deposit		
		Mining Plant	SE
25317	DG&T Working Capital Deposit		
		Mining Plant	SE
25319	Provo Working Capital Deposit		
		Mining Plant	SE
154	Materials and Supplies		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Mining	SE
		General	SO
		Production - Common	SG
		Hydro	SG
		Distribution	SNPD
		Production, Other	SG
163	Stores Expense Undistributed		
		General	SO
25318	Provo Working Capital Deposit		
		Provo Working Capital Deposit	SG
165	Prepayments		
		Direct assigned - Jurisdiction	S
		Property Tax	GPS
		Production, Transmission	SG
		Mining	SE
		General	SO

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT		DESCRIPTION	ALLOCATION FACTOR
182M	Misc Regulatory Assets		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Mining	SE
		General	SO
		Production, Other	SGCT
186M	Misc Deferred Debits		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		General	SO
		Mining	SE
		Production - Common	SG
Working Capital			
CWC	Cash Working Capital		
		Direct assigned - Jurisdiction	S
OWC		Other Working Capital	
131		Cash	SNP
135		Working Funds	SG
143		Other Accounts Receivable	SO
232		Accounts Payable	SO
232		Accounts Payable	SE
253		Deferred Hedge	SE
25330		Other Deferred Credits - Misc	SE
230		Other Deferred Credits - Misc	SE
Miscellaneous Rate Base			
18221	Unrec Plant & Reg Study Costs		
		Direct assigned - Jurisdiction	S
18222	Nuclear Plant - Trojan		
		Trojan Plant	TROJP
		Trojan Plant	TROJD
141	Notes Receivable		
		Employee Loans - Hunter Plant	SG
Rate Base Deductions			
235	Customer Service Deposits		
		Direct assigned - Jurisdiction	S
2281	Prov for Property Insurance		SO
2282	Prov for Injuries & Damages		SO

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
2283	Prov for Pensions and Benefits		SO
22841	Accum Misc Oper Prov-Black Lung		
		Mining	SE
22842	Accum Misc Oper Prov-Trojan		
		Trojan Plant	TROJD
254105	FAS 143 ARO Regulatory Liability		
		Trojan Plant	TROJP
230	Asset Retirement Obligation		
		Trojan Plant	TROJP
252	Customer Advances for Construction		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Customer Related	CN
25399	Other Deferred Credits		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Mining	SE
254	Regulatory Liabilities		
		Regulatory Liabilities	SE
		Insurance Provision	SO
190	Accumulated Deferred Income Taxes		
		Direct assigned - Jurisdiction	S
		Bad Debt	BADDEBT
		Pacific Hydro	SG
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Miscellaneous	SNP
		Trojan	TROJD
		Distribution	SNPD
		Mining Plant	SE
281	Accumulated Deferred Income Taxes		
		Production, Transmission	SG
282	Accumulated Deferred Income Taxes		
		Direct assigned - Jurisdiction	S
		Depreciation	DITBAL
		Hydro Pacific	SG
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Miscellaneous	SNP
		Trojan	TROJP
		Depreciation	TAXDEPR
		Depreciation	SCHMDEXP

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
283	Accumulated Deferred Income Taxes		
		Direct assigned - Jurisdiction	S
		Depreciation	DITBAL
		Hydro Pacific	SG
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Miscellaneous	SNP
		Trojan	TROJD
		Production, Other	SGCT
		Property Tax	GPS
		Mining Plant	SE
255	Accumulated Investment Tax Credit		
		Direct assigned - Jurisdiction	S
		Investment Tax Credits	ITC84
		Investment Tax Credits	ITC85
		Investment Tax Credits	ITC86
		Investment Tax Credits	ITC88
		Investment Tax Credits	ITC89
		Investment Tax Credits	ITC90
		Investment Tax Credits	DGU
PRODUCTION PLANT ACCUM DEPRECIATION			
108SP	Steam Prod Plant Accumulated Depr		
		Steam Plants	SG
108NP	Nuclear Prod Plant Accumulated Depr		
		Nuclear Plant	SG
108HP	Hydraulic Prod Plant Accum Depr		
		Pacific Hydro	SG
		East Hydro	SG
108OP	Other Production Plant - Accum Depr		
		Other Production Plant	SG
TRANS PLANT ACCUM DEPR			
108TP	Transmission Plant Accumulated Depr		
		Transmission Plant	SG
DISTRIBUTION PLANT ACCUM DEPR			
108360 - 108373	Distribution Plant Accumulated Depr		
		Direct assigned - Jurisdiction	S
108D00	Unclassified Dist Plant - Acct 300		
		Direct assigned - Jurisdiction	S
108DS	Unclassified Dist Sub Plant - Acct 300		
		Direct assigned - Jurisdiction	S
108DP	Unclassified Dist Sub Plant - Acct 300		
		Direct assigned - Jurisdiction	S

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
GENERAL PLANT ACCUM DEPR			
108GP	General Plant Accumulated Depr		
		Distribution	S
		Pacific Hydro	SG
		East Hydro	SG
		Production / Transmission	SG
		Customer Related	CN
		General SO	SO
		Mining Plant	SE
		Customer Related	CN
108MP	Mining Plant Accumulated Depr.		
		Mining Plant	SE
108MP	Less Centralia Situs Depreciation		
		Direct assigned - Jurisdiction	S
1081390	Accum Depr - Capital Lease		
		General	SO
1081399	Accum Depr - Capital Lease		
		Direct assigned - Jurisdiction	S
ACCUM PROVISION FOR AMORTIZATION			
111SP	Accum Prov for Amort-Steam		
		Steam Plants	SG
111GP	Accum Prov for Amort-General		
		Distribution	S
		Pacific Hydro	SG
		East Hydro	SG
		Production / Transmission	SG
		Customer Related	CN
		General SO	SO
111HP	Accum Prov for Amort-Hydro		
		Pacific Hydro	SG
		East Hydro	SG
111IP	Accum Prov for Amort-Intangible Plant		
		Distribution	S
		Pacific Hydro	SG
		Production, Transmission	SG
		General	SO
		Mining	SE
		Customer Related	CN
111IP	Less Non-Utility Plant		
		Direct assigned - Jurisdiction	S
111399	Accum Prov for Amort-Mining		
		Mining Plant	SE

APPENDIX C

2010 Protocol - Appendix C
Allocation Factors
Algebraic Derivations

September 15, 2010

Allocation Factors

PacifiCorp serves eight jurisdictions. Jurisdictions are represented by the index i = California, Idaho, Oregon, Utah, Washington, Eastern Wyoming, Western Wyoming, & FERC.

The following assumptions are made in the factor derivations:

It is assumed that the 12CP (j=1 to 12) method is used in defining the System Capacity ("SC").

It is assumed that twelve months (j=1 to 12) method is used in defining the System Energy ("SE").

In defining the System Generation ("SG") factor, the weighting of 75 percent System Capacity, 25 percent System Energy is assumed to continue.

While it is agreed that the peak loads & input energy should be temperature adjusted, no decision has been made upon the methodology to do these adjustments.

System Capacity Factor ("SC")

$$SCi = \frac{\sum_{j=1}^{12} TAP_{ij}}{\sum_{i=1}^{8} \sum_{j=1}^{12} TAP_{ij}}$$

where:

SC_i	=	**System Capacity Factor** for jurisdiction i.
TAP_{ij}	=	Temperature Adjusted Peak Load of jurisdiction i in month j at the time of the System Peak.

System Energy Factor ("SE")

$$SEi = \frac{\sum_{j=1}^{12} TAE_{ij}}{\sum_{i=1}^{8}\sum_{j=1}^{12} TAE_{ij}}$$

where:

SE_i = **System Energy Factor** for jurisdiction i.
$TAEi_j$ = Temperature Adjusted Input Energy of jurisdiction i in month j.

System Generation Factor ("SG")

$$SG_i = .75 * SC_i + .25 * SE_i$$

where:

SG_i = **System Generation Factor** for jurisdiction i.
SC_i = System Capacity for jurisdiction i.
SE_i = System Energy for jurisdiction i.

Mid-C Factor ("MC")

$$MC_i = \frac{WMCE_i}{\sum_{i=1}^{i=8} WMCE_i}$$

where:

MCi = **Mid-C Factor** for jurisdiction i.

$WMCE_i = E^*_{ipr} + (E_{rr} * SGi) + (E_{wa} * WWA_i) + (E_w * SGi)$ Weighted Mid-C Contracts annual energy generation

where:

$E^*_{ipr} = E_{ipr}$ If i is Oregon, otherwise

$E^*_{ipr} = 0$

E_{ipr} = Annual Energy generation of Priest Rapids.

E_{rr} = Annual Energy generation of Rocky Reach.

E_{wa} = Annual Energy generation of Wanapum.

E_w = Annual Energy generation of Wells.

$WWA_i = \frac{SG^*_i}{\sum_{i=1}^{i=8} SG^*_i}$ Weighted Wanapum Energy

where:

$SG^*_i = SG_i$ if i is Washington or Oregon jurisdiction, otherwise

$SG^*_i = 0$.

SG_i = System Generation for jurisdiction i.

<u>Division Generation - Pacific Factor ("DGP")</u>

$$DGP_i = \frac{SG^*_i}{\sum_{i=1}^{i=8} SG^*_i}$$

where:

DGP_i = **Division Generation - Pacific Factor** for jurisdiction i.

$SG_i^* = SG_i$ if i is a Pacific jurisdiction, otherwise

$SG_i^* = 0.$

SG_i = System Generation for jurisdiction i.

Division Generation - Utah Factor ("DGU")

$$DGU_i = \frac{SG_i^*}{\sum_{i=1}^{i=8} SG_i^*}$$

where:

DGU_i = **Division Generation - Utah Factor** for jurisdiction i.

$SG_i^* = SG_i$ if i is a Utah jurisdiction, otherwise

$SG_i^* = 0.$

SG_i = System Generation for jurisdiction i.

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Case No. PAC-E-10-09
Witness: Andrea L. Kelly

System Net Plant - Distribution Factor ("SNPD")

$$SNPD_i = \frac{PD_i - ADPD_i}{(PD - ADPD)}$$

where:

$SNPD_i$	=	**System Net Plant - Distribution Factor** for jurisdiction i.
PD_i	=	Distribution Plant - for jurisdiction i.
$ADPD_i$	=	Accumulated Depreciation Distribution Plant - for jurisdiction i.
PD	=	Distribution Plant.
$ADPD$	=	Accumulated Depreciation Distribution Plant.

<u>System Gross Plant - System Factor ("GPS")</u>

$$GPS_i = \frac{PP_i + PT_i + PD_i + PG_i + PI_i}{\sum_{i=1}^{i=8}(PP_i + PT_i + PD_i + PG_i + PI_i)}$$

$GP\text{-}S_i$	=	**Gross Plant - System Factor** for jurisdiction i.
PP_i	=	Production Plant for jurisdiction i.
PT_i	=	Transmission Plant for jurisdiction i.
PD_i	=	Distribution Plant for jurisdiction i.
PG_i	=	General Plant for jurisdiction i.
PI_i	=	Intangible Plant for jurisdiction i.

<u>System Net Plant Factor ("SNP")</u>

$$SNP_i = \frac{PP_i + PT_i + PD_i + PG_i + PI_i - ADPP_i - ADPT_i - ADPD_i - ADPG_i - ADPI_i}{\sum_{i=1}^{i=8}(PP_i + PT_i + PD_i + PG_i + PI_i - ADPPi - ADPT_i - ADPD_i - ADPG_i - ADPI_i)}$$

SNP_i	=	**System Net Plant Factor** for jurisdiction i.
PP_i	=	Production Plant for jurisdiction i.
PT_i	=	Transmission Plant for jurisdiction i.
PD_i	=	Distribution Plant for jurisdiction i.
PG_i	=	General Plant for jurisdiction i.
PI_i	=	Intangible Plant for jurisdiction i.
$ADPP_i$	=	Accumulated Depreciation Production Plant for jurisdiction i.
$ADPT_i$	=	Accumulated Depreciation Transmission Plant for jurisdiction i.
$ADPD_i$	=	Accumulated Depreciation Distribution Plant for jurisdiction i.
$ADPG_i$	=	Accumulated Depreciation General Plant for jurisdiction i.
$ADPI_i$	=	Accumulated Depreciation Intangible Plant for jurisdiction i.

System Overhead - Gross Factor ("SO")

$$SOG_i = \frac{PP_i + PT_i + PD_i + PG_i + PI_i - PP_{oi} - PT_{oi} - PD_{oi} - PG_{oi} - PI_{oi}}{\sum_{i=1}^{i=8}(PP_i + PT_i + PD_i + PG_i + PP_i - PP_{o}i - PI_{oi} - PD_{oi} - PG_{oi} - PI_{oi})}$$

SOG_i	=	**System Overhead - Gross Factor** for jurisdiction i.
PP_i	=	Gross Production Plant for jurisdiction i.
PT_i	=	Gross Transmission Plant for jurisdiction i.
PD_i	=	Gross Distribution Plant for jurisdiction i.
PG_i	=	Gross General Plant for jurisdiction i.
PI_i	=	Gross Intangible Plant for jurisdiction i.
PP_{oi}	=	Gross Production Plant for jurisdiction i allocated on a SO factor.
PT_{oi}	=	Gross Transmission Plant for jurisdiction i allocated on a SO factor
PD_{oi}	=	Gross Distribution Plant for jurisdiction i allocated on a SO factor
PG_{oi}	=	Gross General Plant for jurisdiction i allocated on a SO factor
PI_{oi}	=	Gross Intangible Plant for jurisdiction i allocated on a SO factor

<u>Bad Debt Expense Factor ("BADDEBT")</u>

$$BADDEBT_i = \frac{ACCT904_i}{\sum_{i=1}^{i=8} ACCT904_i}$$

$BADDEBT_i$ = **Bad Debt Expense Factor** for jurisdiction i.
$ACCT904i$ = Balance in Account 904 for jurisdiction i.

<u>Customer Number Factor ("CN")</u>

$$CN_i = \frac{CUST_i}{\sum_{i=1}^{i=8} CUST_i}$$

where:
CN_i = **Customer Number Factor** for jurisdiction i.
$CUST_i$ = Total Electric Customers for jurisdiction i.

<u>Contributions in Aid of Construction ("CIAC")</u>

$$CIAC_i = \frac{CIACNA_i}{\sum_{i=1}^{i=8} CIACNA_i}$$

where:
$CIAC_i$ = **Contributions in Aid of Construction Factor** for jurisdiction i.
$CIACNA_i$ = Contributions in Aid of Construction – Net additions for jurisdiction i.

Schedule M - Deductions ("SCHMDEXP")

$$SCHMDEXP_i = \frac{DEPRC_i}{\sum_{i=1}^{i=8} DEPRC_i}$$

where:

$SCHMDEXP_i$	=	**Schedule M - Deductions (SCHMDEXP) Factor** for jurisdiction i.
$DEPRC_i$	=	Depreciation in Accounts 403.1 - 403.9 for jurisdiction i.

Trojan Plant ("TROJP")

$$TROJP_i = \frac{ACCT18222_i}{\sum_{i=1}^{i=8} ACCT18222_i}$$

where:

$TROJP_i$	=	**Trojan Plant (TROJP) Factor** for jurisdiction i.
$ACCT18222_i$	=	Allocated Adjusted Balance in Account 182.22 for jurisdiction i.

Trojan Decommissioning ("TROJD")

$$TROJD_i = \frac{ACCT22842_i}{\sum_{i=1}^{i=8} ACCT22842_i}$$

where:

$TROJD_i$	=	**Trojan Decommissioning (TROJD) Factor** for jurisdiction i.
$ACCT22842_i$	=	Allocated Adjusted Balance in Account 228.42 for jurisdiction i.

Tax Depreciation ("TAXDEPR")

$$TAXDEPR_i = \frac{TAXDEPRA_i}{\sum_{i=1}^{i=8} TAXDEPRA_i}$$

where:

$TAXDEPR_i$ = **Tax Depreciation (TAXDEPR) Factor** for jurisdiction i.
$TAXDEPRA_i$ = Tax Depreciation allocated to jurisdiction i.

(Tax Depreciation is allocated based on functional pre merger and post merger splits of plant using Divisional and System allocations from above. Each jurisdiction's total allocated portion of Tax depreciation is determined by its total allocated ratio of these functional pre and post merger splits to the total Company Tax Depreciation.)

Deferred Tax Expense ("DITEXP")

$$DITEXP_i = \frac{DITEXPA_i}{\sum_{i=1}^{i=8} DITEXPA_i}$$

where:

$DITEXP_i$ = **Deferred Tax Expense (DITEXP) Factor** for jurisdiction i.
$DITEXPA_i$ = Deferred Tax Expense allocated to jurisdiction i.

(Deferred Tax Expense is allocated by a run of PowerTax based upon the above factors. PowerTax is a computer software package used to track Deferred Tax Expense & Deferred Tax Balances. PowerTax allocates Deferred Tax Expense and Deferred Tax Balances to the states based upon a computer run which uses as inputs the preceding factors. If the preceding factors change, the factors generated by PowerTax change.)

Deferred Tax Balance ("DITBAL")

$$DITBAL_i = \frac{DITBALA_i}{\sum_{i=1}^{i=8} DITBALA_i}$$

where:

$DITBAL_i$	=	**Deferred Tax Balance (DITBAL) Factor** for jurisdiction i.
$DITBALA_i$	=	Deferred Tax Balance allocated to jurisdiction i.

(Deferred Tax Balance is allocated by a run of PowerTax based upon the above factors. PowerTax is a computer software package used to track Deferred Tax Expense & Deferred Tax Balances. PowerTax allocates Deferred Tax Expense and Deferred Tax Balances to the states based upon a computer run which uses as inputs the preceding factors. If the preceding factors change, the factors generated by PowerTax change.)

APPENDIX D

2010 Protocol - Appendix D
Special Contracts

Special Contracts without Ancillary Service Contract Attributes

For allocation purposes Special Contracts without identifiable Ancillary Service Contract attributes are viewed as one transaction.

Loads of Special Contract customers will be included in all Load-Based Dynamic Allocation Factors.

When interruptions of a Special Contract customer's service occur, the reduction in load will be reflected in the host jurisdiction's Load-Based Dynamic Allocation Factors.

Actual revenues received from Special Contract customer will be assigned to the State where the Special Contract customer is located.

See example in Table 1

Special Contracts with Ancillary Service Contract Attributes

For allocation purposes Special Contracts with Ancillary Service Contract attributes are viewed as two transactions. PacifiCorp sells the customer electricity at the retail service rate and then buys the electricity back during the interruption period at the Ancillary Service Contract rate.

Loads of Special Contract customers will be included in all Load-Based Dynamic Allocation Factors.

When interruptions of a Special Contract customer's service occur, the host jurisdiction's Load-Based Dynamic Allocation Factors and the retail service revenue are calculated as though the interruption did not occur.

Revenues received from Special Contract customer, before any discounts for Customer Ancillary Service attributes of the Special Contract, will be assigned to the State where the Special Contract customer is located.

Discounts from tariff prices provided for in Special Contracts that recognize the Customer Ancillary Service Contract attributes of the Contract, and payments to retail customers for Customer Ancillary Services will be allocated among States on the same basis as System Resources.

See example in Table 2

Buy-through of Economic Curtailment

When a buy-through option is provided with economic curtailment, the load, costs and revenue associated with a customer buying through economic curtailment will be excluded from the calculation of State revenue requirements. The cost associated with the buy-through will be removed from the calculation of net power costs, the Special Contract customer load associated with the buy-through will be not be included in the calculation of Load-Based Dynamic Allocation Factors, and the revenue associated with the buy-through will not be included in State revenues.

2010 Protocol - Appendix D - Table 1
Interruptible Contract Without Ancillary Service Contract Attributes
Effect on Revenue Requirement

		Factor	Total system	Jurisdiction 1	Jurisdiction 2	Jurisdiction 3
1	**Loads**					
2	Jurisdictional Loads - No Interruptible Service					
3	Jurisdictional Sum of 12 monthly CP demand (MW)		72,000	24,000	36,000	12,000
4	Jurisdictional Annual Energy (MWh)		42,000,000	14,000,000	21,000,000	7,000,000
5						
6	Jurisdictional Loads - With Interruptible Service - Reflecting Actual Interruptions					
7	Jurisdictional Sum of 12 monthly CP demand (MW)		71,700	24,000	35,700	12,000
8	Jurisdictional Annual Energy (MWh)		41,962,500	14,000,000	20,962,500	7,000,000
9						
10	Special Contract Customer Revenue and Load - Non Interruptible Service					
11	Special Contract Customer Revenue		$ 20,000,000		$ 20,000,000	
12	Special Contract Customer Sum of 12 CPs (MW) (Included in line 2)		900	-	900	-
13	Special Contract Annual Energy (MWh) (Included in line 3)		500,000	-	500,000	-
14						
15	Special Contract Customer Revenue and Load - With Interruptible Service (75 MW X 500 Hours of Interruption)					
16	Special Contract Customer Revenue		$ 16,000,000		$ 16,000,000	
17	Discount for Ancillary Services				-	
18	Net Cost to Special Contract Customer		$ 16,000,000		$ 16,000,000	
19	Special Contract Sum of 12 CP- Reflecting Actual Interruptions (MW) (Included in line 7)		600	-	600	-
20	Special Contract Annual Energy- Reflecting Actual Interruptions (MWh) (Included in line 8)		462,500	-	462,500	-
21						
22	System Cost Savings from Interruption		$4,000,000			
23						
24	**Allocation Factors**					
25	No Interruptible Service					
26	SE factor (Calculated from line 4)	SE1	100.00%	33.33%	50.00%	16.67%
27	SC factor (Calculated from line 3)	SC1	100.00%	33.33%	50.00%	16.67%
28	SG factor (line 27*75% + line 26*25%)	SG1	100.00%	33.33%	50.00%	16.67%
29						
30	With Interruptible Service (Reflecting Actual Physical Interruptions)					
31	SE factor (Calculated from line 8)	SE2	100.00%	33.36%	49.96%	16.68%
32	SC factor (Calculated from line 7)	SC2	100.00%	33.47%	49.79%	16.74%
33	SG factor (line 32*75% + line 31*25%)	SG2	100.00%	33.45%	49.83%	16.72%
34						
35						
36	**No Interruptible Service**					
37						
38	**Cost of Service**					
39	Energy Cost	SE1	$ 500,000,000	$ 166,666,667	$ 250,000,000	$ 83,333,333
40	Demand Related Costs	SG1	$ 1,000,000,000	$ 333,333,333	$ 500,000,000	$ 166,666,667
41	Sum of Cost		$ 1,500,000,000	$ 500,000,000	$ 750,000,000	$ 250,000,000
42						
43	**Revenues**					
44	Special Contract Revenue	Situs	$ 20,000,000		$ 20,000,000	
45	**Revenues from all other customers**	Situs	**$ 1,480,000,000**	**$ 500,000,000**	**$ 730,000,000**	**$ 250,000,000**
46						
47						
48	**With Interruptible Service**					
49						
50	**Cost of Service**					
51	Energy Cost	SE2	$ 498,000,000	$ 166,148,347	$ 248,777,480	$ 83,074,173
52	Demand Related Costs	SG2	$ 998,000,000	$ 334,058,577	$ 496,912,134	$ 167,029,289
53	Sum of Cost		$ 1,496,000,000	$ 500,206,924	$ 745,689,614	$ 250,103,462
54						
55	**Revenues**					
56	Special Contract Revenue	Situs	$ 16,000,000		$ 16,000,000	
57	**Revenues from all other customers**	Situs	**$ 1,480,000,000**	**$ 500,206,924**	**$ 729,689,614**	**$ 250,103,462**

2010 Protocol - Appendix D - Table 2
Interruptible Contract With Ancillary Service Contract Attributes
Effect on Revenue Requirement

	Factor	Total system	Jurisdiction 1	Jurisdiction 2	Jurisdiction 3
1 **Loads**					
2 Jurisdictional Loads - No Interruptible Service					
3 Jurisdictional Sum of 12 monthly CP demand (MW)		72,000	24,000	36,000	12,000
4 Jurisdictional Annual Energy (MWh)		42,000,000	14,000,000	21,000,000	7,000,000
5					
6 Jurisdictional Loads - With Interruptible Service - Reflecting Actual Interruptions					
7 Jurisdictional Sum of 12 monthly CP demand (MW)		71,700	24,000	35,700	12,000
8 Jurisdictional Annual Energy (MWh)		41,962,500	14,000,000	20,962,500	7,000,000
9					
10 Special Contract Customer Revenue and Load - Non Interruptible Service					
11 Special Contract Customer Revenue		$ 20,000,000		$ 20,000,000	
12 Special Contract Customer Sum of 12 CPs (MW) (Included in line 2)		900	-	900	-
13 Special Contract Annual Energy (MWh) (Included in line 3)		500,000	-	500,000	-
14					
15 Special Contract Customer Revenue and Load - With Interruptible Service (75 MW X 500 Hours of Interruption)					
16 Tariff Equivalent Revenue		$ 20,000,000		$ 20,000,000	
17 Ancillary Service Discount for 75 MW X 500 Hours of Economic Curtailment				$ (4,000,000)	
18 Net Cost to Special Contract Customer		$ 16,000,000		$ 16,000,000	
19 Special Contract Sum of 12 CP- Reflecting Actual Interruptions (MW) (Included in line 7)		600	-	600	-
20 Special Contract Annual Energy- Reflecting Actual Interruptions (MWh) (Included in line 8)		462,500	-	462,500	-
21					
22 System Cost Savings from Interruption		$4,000,000			
23					
24 **Allocation Factors**					
25 No Interruptible Service					
26 SE factor (Calculated from line 4)	SE1	100.00%	33.33%	50.00%	16.67%
27 SC factor (Calculated from line 3)	SC1	100.00%	33.33%	50.00%	16.67%
28 SG factor (line 27*75% + line 26*25%)	SG1	100.00%	33.33%	50.00%	16.67%
29					
30 With Interruptible Service (Reflecting Actual Physical Interruptions)					
31 SE factor (Calculated from line 8)	SE2	100.00%	33.36%	49.96%	16.68%
32 SC factor (Calculated from line 7)	SC2	100.00%	33.47%	49.79%	16.74%
33 SG factor (line 32*75% + line 31*25%)	SG2	100.00%	33.45%	49.83%	16.72%
34					
35					
36 **No Interruptible Service**					
37					
38 **Cost of Service**					
39 Energy Cost	SE1	$ 500,000,000	$ 166,666,667	$ 250,000,000	$ 83,333,333
40 Demand Related Costs	SG1	$ 1,000,000,000	$ 333,333,333	$ 500,000,000	$ 166,666,667
41 Sum of Cost		$ 1,500,000,000	$ 500,000,000	$ 750,000,000	$ 250,000,000
42					
43 **Revenues**					
44 Special Contract Revenue	Situs	$ 20,000,000		$ 20,000,000	
45 **Revenues from all other customers**	Situs	**$ 1,480,000,000**	**$ 500,000,000**	**$ 730,000,000**	**$ 250,000,000**
46					
47					
48 **With Interruptible Service & Ancillary Service Contract**					
49					
50 **Cost of Service**					
51 Energy Cost	SE1	$ 498,000,000	$ 166,000,000	$ 249,000,000	$ 83,000,000
52 Demand Related Costs	SG1	$ 998,000,000	$ 332,666,667	$ 499,000,000	$ 166,333,333
53 Ancillary Service Contract - Economic Curtailment (Demand)	SG1	$ 2,000,000	$ 666,667	$ 1,000,000	$ 333,333
54 Ancillary Service Contract - Economic Curtailment (Energy)	SE1	$ 2,000,000	$ 666,667	$ 1,000,000	$ 333,333
55 Sum of Cost		$ 1,500,000,000	$ 500,000,000	$ 750,000,000	$ 250,000,000
56					
57 **Revenues**					
58 Special Contract Revenue	Situs	$ 20,000,000		$ 20,000,000	
59 **Revenues from all other customers**	Situs	**$ 1,480,000,000**	**$ 500,000,000**	**$ 730,000,000**	**$ 250,000,000**

APPENDIX E

2010 Protocol - Appendix E
6 Year Levelized ECD Hydro Endowment Fixed Dollar Proposal
Revenue Requirement ($000)

2011	**Total**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**
Klamath Surcharge Situs	(1)	1,062	11,496	(1,286)	(7,272)	(976)	(2,955)	(70)
ECD Hydro	(0)	(23)	(6,851)	(745)	6,240	836	484	60
Total	(1)			(2,031)	(1,032)	(140)	(2,471)	(10)

2012	**Total**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**
Klamath Surcharge Situs	(1)	1,062	11,496	(1,286)	(7,272)	(976)	(2,955)	(70)
ECD Hydro	(0)	(23)	(6,851)	(745)	6,240	836	484	60
Total	(1)			(2,031)	(1,032)	(140)	(2,471)	(10)

2013	**Total**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**
Klamath Surcharge Situs	(1)	1,062	11,496	(1,286)	(7,272)	(976)	(2,955)	(70)
ECD Hydro	(0)	(23)	(6,851)	(745)	6,240	836	484	60
Total	(1)			(2,031)	(1,032)	(140)	(2,471)	(10)

2014	**Total**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**
Klamath Surcharge Situs	(1)	1,062	11,496	(1,286)	(7,272)	(976)	(2,955)	(70)
ECD Hydro	(0)	(23)	(6,851)	(745)	6,240	836	484	60
Total	(1)			(2,031)	(1,032)	(140)	(2,471)	(10)

2015	**Total**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**
Klamath Surcharge Situs	(1)	1,062	11,496	(1,286)	(7,272)	(976)	(2,955)	(70)
ECD Hydro	(0)	(23)	(6,851)	(745)	6,240	836	484	60
Total	(1)			(2,031)	(1,032)	(140)	(2,471)	(10)

2016	**Total**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**
Klamath Surcharge Situs	(1)	1,062	11,496	(1,286)	(7,272)	(976)	(2,955)	(70)
ECD Hydro	(0)	(23)	(6,851)	(745)	6,240	836	484	60
Total	(1)			(2,031)	(1,032)	(140)	(2,471)	(10)

6 Year NPV 2011-2016 @ 7.36%	**Total**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**
Klamath Surcharge Situs	(3)	5,008	54,194	(6,064)	(34,278)	(4,601)	(13,932)	(330)
ECD Hydro	(0)	(106)	(32,298)	(3,511)	29,414	3,939	2,281	281
Total	(3)			(9,575)	(4,864)	(662)	(11,650)	(49)

APPENDIX F

2010 Protocol - Appendix F
Methodology for Determining Mid-C (MC) Factor

Energy for each Mid-C contract is allocated as follows to determine the MC factor.

- Priest Rapids energy is assigned 100% to Oregon.
- Rocky Reach energy is allocated on the SG factor.
- Wanapum energy is assigned to Oregon and Washington based upon each state's respective share of the SG factor.
  - Wanapum energy assigned to Oregon = Oregon SG / (total Oregon and Washington SG).
  - Wanapum energy assigned to Washington = Washington SG / (total Oregon and Washington SG).
- Wells energy is allocated on the SG factor.
- The Grant replacement contracts begin at the time the Priest Rapids contract terminates. The energy from these contracts is assigned to Oregon through October 31, 2009.
- Effective November 1, 2009, the date the Wanapum contract expires, the Grant replacement contract energy is divided into two pieces based on PacifiCorp's share of the nameplate of Priest Rapids and Wanapum as shown in the following calculation:

	Nameplate Capacity MW	PacifiCorp's Share - %	PacifiCorp's Share of Nameplate - MW	PacifiCorp's Share of Nameplate - %
Priest Rapids	789	13.9%	110	41.35%
Wanapum	831	18.7%	155	58.65%
	1,620		265	100.00%

- The Priest Rapids portion of the Grant County replacement contracts is 41.35%. The energy associated with the Grant County replacement contracts for Priest Rapids is assigned 100% to Oregon.
- The Wanapum portion of the Grant County replacement contracts is 58.65%. The energy associated with the Grant County replacement contracts for Wanapum is assigned to Washington based on the ratio of the Washington SG factor to the sum of the Oregon and Washington SG factors. The remaining energy from the Wanapum portion is assigned to Oregon.

After all of the energy from the Mid-Columbia Contracts has been assigned or allocated to each State, then the MC factor is created by dividing each State's energy by the total energy associated with the Mid-Columbia Contracts. The MC factor is used to allocate the Mid-Columbia Contract embedded cost differential to each State.

2010 Protocol - Appendix F
Allocation of Each Mid-Columbia Contract

Factors Used to Allocate Mid C Energy to Jurisdictions

2005 — Percent

Mid C Contracts	Priest Rapids 1/	Rocky Reach 2/	Wanapum 3/	Wells 4/	Priest Grant Replacement 5/	Wanapum Grant Replacement 5/
California		1.80%		1.80%		
Oregon	100.00%	28.86%	76.94%	28.86%	100.00%	76.94%
Washington		8.65%	23.06%	8.65%	0.00%	23.06%
Utah		41.93%		41.93%		
Idaho		5.85%		5.85%		
Wyoming		12.91%		12.91%		
	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

2007 — Percent

Mid C Contracts	Priest Rapids 1/	Rocky Reach 2/	Wanapum 3/	Wells 4/	Priest Grant Replacement 5/	Wanapum Grant Replacement 5/
California		1.73%		1.73%		
Oregon	100.00%	27.56%	76.68%	27.56%	100.00%	76.68%
Washington		8.38%	23.32%	8.38%	0.00%	23.32%
Utah		44.13%		44.13%		
Idaho		5.59%		5.59%		
Wyoming		12.61%		12.61%		
	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

2011 — Percent

Mid C Contracts	Priest Rapids 1/	Rocky Reach 2/	Wanapum 3/	Wells 4/	Priest Grant Replacement 5/	Wanapum Grant Replacement 5/
California		1.65%		1.65%		
Oregon	100.00%	26.13%	76.18%	26.13%	100.00%	76.18%
Washington		8.17%	23.82%	8.17%	0.00%	23.82%
Utah		46.96%		46.96%		
Idaho		5.20%		5.20%		
Wyoming		11.90%		11.90%		
	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Calculation of Mid C Factor

2005 — MWh

Mid C Contracts	Priest Rapids 1/	Rocky Reach 2/	Wanapum 3/	Wells 4/	Priest Grant Replacement 5/	Wanapum Grant Replacement 5/	Total Mid-C	MC Factor %
California		5,658		4,749			10,407	0.54%
Oregon	567,559	90,829	596,498	76,238	-	-	1,331,125	69.27%
Washington		27,222	178,772	22,849			228,842	11.91%
Utah		131,984		110,783			242,767	12.63%
Idaho		18,426		15,466			33,892	1.76%
Wyoming		40,636		34,108			74,744	3.89%
	567,559	314,754	775,270	264,193	-	-	1,921,777	100.00%

2007 — MWh

Mid C Contracts	Priest Rapids 1/	Rocky Reach 2/	Wanapum 3/	Wells 4/	Priest Grant Replacement 5/	Wanapum Grant Replacement 5/	Total Mid-C	MC Factor %
California		5,457		4,581			10,038	0.52%
Oregon	-	86,746	594,444	72,811	564,683	-	1,318,684	68.72%
Washington		26,388	180,826	22,149			229,363	11.95%
Utah		138,899		116,587			255,486	13.31%
Idaho		17,582		14,758			32,340	1.69%
Wyoming		39,682		33,308			72,990	3.80%
	-	314,754	775,270	264,193	564,683	-	1,918,900	100.00%

2011 — MWh

Mid C Contracts	Priest Rapids 1/	Rocky Reach 2/	Wanapum 3/	Wells 4/	Priest Grant Replacement 5/	Wanapum Grant Replacement 5/	Total Mid-C	MC Factor %
California		5,200		4,365			9,565	0.65%
Oregon	-	82,231	-	69,021	372,327	402,325	925,904	62.59%
Washington		25,708	-	21,579	-	125,776	173,064	11.70%
Utah		147,810		124,066			271,876	18.38%
Idaho		16,353		13,726			30,079	2.03%
Wyoming		37,452		31,436			68,887	4.66%
	-	314,754	-	264,193	372,327	528,101	1,479,375	100.00%

(1) Priest Rapids Power Sales Agreement with Grant County dated May 2, 1956
(2) Rocky Reach Power Sales Agreement with Chelan County dated November 14, 1957
(3) Wanapum Power Sales Agreement with Grant County dated June 22, 1959
(4) Wells Power Sales Agreement with Douglas County dated September 18, 1963
(5) Priest Rapids Project Product Sales Agreement with Grant County dated December 31, 2001
The Additional Product Sales Agreement with Grant County dated December 31, 2001
The Priest Rapids Reasonable Portion Power Sales Agreement with Grant County dated December 31, 2001